BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program.	Rulemaking 06-02-012

PRE-WORKSHOP COMMENTS OF
SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)
REGARDING SB 1036 IMPLEMENTATION

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I. INTRODUCTION AND BACKGROUND

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission"), and the April 25, 2008 Energy Division request for pre-workshop comments, San Diego Gas & Electric Company ("SDG&E") hereby submits these comments in advance of the workshop to be held on May 29, 2008 regarding implementation of Senate Bill ("SB") 1036.

SB 1036 modifies administration of the Renewable Portfolio Standard ("RPS") program by transferring from the California Energy Commission (the "CEC") to the Commission the authority to award funds to cover the cost of RPS-eligible procurement that exceeds the relevant market price referent ("MPR").[1] Prior to adoption of SB 1036, a portion of the Public Goods Charge ("PGC") paid by electric utility ratepayers was placed in the New Renewable Resources Account ("NRRA") and made available for distribution by the CEC as supplemental energy payments ("SEPs").[2] SB 1036 abolishes the NRRA, requires the CEC to transfer all unencumbered funds in the NRRA back to the

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1 *See* Senate Bill (SB) 1036 (Stats. 2007, Ch. 685).
2 *See* Senate Bill (SB) 1078, Sec. 3, § 399.15(a)(2) (Stats. 2002, Ch. 516).

respective utilities for refund to ratepayers and requires a corresponding adjustment in the PGC to reflect suspension of collection of the renewable energy portion of the PGC.[3]

In addition to the ratemaking adjustments described above, the bill directs the Commission to develop an above-MPR cost limitation for each investor-owned utility ("IOU") that is equivalent to the sum of the NRRA funds returned to that utility pursuant to SB 1036 and the funds that, absent the legislation, would have been collected and placed in the NRRA through January 1, 2012.[4] The cost limitation is expressed in terms of available " Above-MPR Funds" or "AMFs."[5] If the relevant above-MPR cost limitation (*i.e.*, available AMFs) is not sufficient to support an IOU's total above-MPR costs, the Commission must allow the utility to limit its procurement to the quantity of resources that can be procured at or below the MPR.[6] The IOU may, however, voluntarily propose to procure RPS-eligible generation at above-MPR prices after reaching this cost limitation.[7]

Consistent with its stated intent to streamline approval of RPS contracts,[8] SB 1036 sets forth only five pre-conditions for counting above-MPR costs of a PPA against the AMF cost limitation:

> (A) The contract has been approved by the commission and was selected through a competitive solicitation *pursuant to the requirements of subdivision (d) of Section 399.14*.
>
> (B) The contract covers a duration of no less than 10 years.
>
> (C) The contracted project is a new or repowered facility commencing commercial operations on or after January 1, 2005.

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3 *See* SB 1036, Sec. 6, § 25743.
4 *Id.*, Sec. 13, § 399.15(d).
5 Resolution E-4160, p. 2.
6 SB 1036, Sec. 13, § 399.15(d)(3).
7 *Id.*, Sec. 13, § 399.15(d)(4).
8 *See id.* Sec. 1.

> (D) No purchases of renewable energy credits may be eligible for consideration as an above-market cost.
>
> (E) The above-market costs of a contract do not include any indirect expenses including imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades.[9]

All procurement and administrative costs (including above-MPR costs) of a long-term RPS contract approved by the Commission are deemed per se reasonable and recoverable in rates.[10]

On March 12, 2008, the Commission issued Draft Resolution E-4160 (the "Draft Resolution"), which included various proposals related to SB 1036 implementation. It directed the IOUs to make certain ratemaking adjustments, established the cost limitation for above-MPR costs that each IOU can expend on the procurement of eligible renewable energy resources solicited through competitive solicitations, outlined the methodology for an AMF Calculator, and proposed eligibility criteria and guidelines for approving AMF requests. In response to a bifurcation request jointly submitted to the Executive Director by several parties,[11] the Draft Resolution was revised to address only the ratemaking aspects of SB 1036. In the final Resolution E-4160 approved on April 10, 2008, the Commission indicated that the Energy Division would hold a workshop "to allow full consideration" of the remaining SB 1036 implementation issues.[12]

The Energy Division's Request for Pre-Workshop Comments Regarding SB 1036 Implementation (the "Request for Comments") notes that "[t]he purpose of this workshop is to develop a transparent methodology for efficiently and effectively using limited

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9 *Id.*, Sec. 13, § 399.15(d)(2) (emphasis added).
10 *Id.*, Sec. 13, § 399.14(g) and 399.15(d)(4) (Stats. 2007, Ch. 685) (emphasis added).
11 *See* Letter to Paul Clanon from William V. Walsh, dated March 28, 2008.
12 Resolution E-4160, p. 7.

Above-Market Funds (AMFs) in a manner that maximizes benefits for ratepayers, stakeholders, and the RPS Program."[13] The Request for Comments consists of a detailed list of questions concerning AMFs, including questions regarding certain of the proposals originally set forth in the Draft Resolution.

II. DISCUSSION

SDG&E appreciates this opportunity to provide pre-workshop comments on the Commission's efforts to implement SB 1036 and to develop a methodology for use of AMFs. In implementing this legislation, however, the Commission must remain mindful of the need to avoid the inadvertent creation of additional obstacles to RPS compliance. Adoption of more complex and onerous RPS rules will create confusion in the California renewable energy market and will hamper the IOUs' ability to procure renewable energy. Moreover, it makes little sense for the Commission and parties to expend more than minimal time and resources to develop an AMF methodology where the availability of AMFs will be short-lived. SDG&E's cost limitation is a small amount, given current market prices, and its available AMF funds will likely be exhausted with only one or two RPS contracts. SDG&E intends to continue procuring cost-effective renewable energy even after reaching its mandated cost limitation or reaching its 20% target. Thus, rather than devoting scarce resources to developing a complex set of rules related to AMFs, the Commission should focus its energy on simplifying existing RPS rules in order to encourage and support the IOUs' efforts to expand their respective RPS portfolios beyond any statutory cap or minimum.

[13] Request for Comments, p. 1.

Because the IOUs will likely reach their cost caps relatively quickly, the Commission's concerns regarding the appropriate MPR for AMF calculation purposes may also soon be rendered moot, since the MPR's remaining role is to determine the need for AMFs. In any event, SDG&E is unsure why the reasonableness of RPS contracts is relevant to the SB 1036 implementation process and discussion, given the fact that the Commission in the Draft Resolution made clear that the MPR is not used to judge the reasonableness of transactions, but is solely used in the calculation of AMFs.[14] Seemingly, the Commission is inappropriately mixing and matching proceedings, as this proceeding involves simple accounting, not a reasonableness review of RPS contracts.

SDG&E addresses the Energy Division's pre-workshop questions below. In addition, SDG&E submits that there are no material factual disputes that require evidentiary hearings.

III. PRE-WORKSHOP QUESTIONS AND RESPONSES

1. *The cost limitations established by SB 1036 involve summing funds that would have been collected over several years. SB 1036 does not suggest that a discount rate should be applied to the calculation of the limit. Yet, the funds do impose real costs and benefits on various stakeholders, each with a different perspective on the time value of money.*

    - *Discuss whether a discount rate should be applied to the cost limitation calculation.*

      Response:

      The limit and the withdrawals from it should be computed consistently. As it stands, the funds from the MPR–to-contract are in nominal dollars and the total funds in the limiting pot are as well. If some party needs to change the approach, it should be remembered that the "over MPR" levelized number must be converted to a NPV and this would obviously involve a discount rate. The two calculations (the cost limitation and the over-MPR amount) for a given utility should use the same discount rate.

[14] Draft Resolution, at p. 12 (stating, "the reasonableness of the [transaction] price can not be directly evaluated by the Market Price Referent.").

- *Absent SB 1036, would the PGC funds collected have been subject to financing charges, interest payments or a discount rate that would directly or indirectly affect the cost limitations? If yes, please cite the legislation, documentation, precedent, or practice on which you base your answer.*

  Response:

  No, there is no reason to believe the PGC funds would ever have become a revenue requirement. They would have been applied to reduce revenue requirements.

- *Please provide a spreadsheet calculation (and all supporting documentation) if you propose a calculation that differs from the calculation proposed in Draft Resolution E-4160.*

  Response:

  Please see the attached spreadsheet for an example.

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2. *Attached to this Pre-Workshop Comment Request is the Staff's proposed AMFs Calculator. Prior to SB 1036, the CEC's proposed method for calculating above-market costs was to calculate the difference between the levelized bid price and the applicable levelized MPR. The nominal sum of that difference represented the total amount of SEP funds requested by the generator, and was then to be paid over the life of the contract. With SB 1036, funds for AMFs will not be collected up-front through the public goods charge, but rather will be recovered in utility rates.*

   - *Should a discount rate be applied to the AMFs request of an RPS contract? If so, should the discount rate be the utility's authorized WACC or another discount rate? Please provide a credible public source of data for establishing another discount rate.*

     Response:

     If a discount rate is used for the benchmark then the same one should be used for the annuitized AMFs. The discount rate should be the WACC of the subject utility.

3. *Comment on whether contracts with prolonged negotiations (e.g. the contract is executed more than 18 months since the close of the solicitation in which it bid) or projects that have significantly changed since the original bid should be considered bilateral contracts and thus not eligible for AMFs.*

   Response:

The 18 month rules is not part of statute, is arbitrary and has no logical connection with the issue of AMFs.

Contract negotiation is a complicated, involved process. Frequently, bidders are still developing projects while negotiating with IOUs and are not prepared to execute a binding agreement until their project achieves certain milestones. (Alternately, counterparties could quickly reach agreement on a contract to meet an arbitrary deadline, with that contract containing so many conditions precedent as to make it completely non-binding). As long the final PPA submitted for the CPUC's consideration is not materially different from the initial proposal and the price is not significantly different from the initial offered price without a value-added trade-off, there should not be an 18 month deadline.

Markets may arguably change over 18 months. The major milestones in a project's development span far longer than 18 months. For example, it may take a project many months to acquire BLM land, many months to obtain permitting, but during negotiations the developer has obtained significant financial backing or has obtained credible wind data, etc. Limiting negotiation to an arbitrary 18-months disregards the nature of project evolution.

Bilateral contracts, which have been compared to the results of a recent competitive solicitation, should not be disqualified for AMFs. In fact, all bilateral contracts that SDG&E considers are put to the LCBF test, compared to all offers received in the most recent solicitation, and thus are in essence competing with all other offers. This makes the resultant contract price a market tested value that should qualify for AMFs along with projects resulting from actual bids into the RFOs.

4. *Identify what is the appropriate MPR to calculate an AMFs request for a contract in each of the following situations:*

- *With prolonged negotiations (e.g. a contract executed more than 18 months after the close of the solicitation);*

  Response:

  For reasons stated above, the appropriate MPR to calculate an AMF request for a contract is the prevailing MPR at the time the project was initially proposed. While it may be useful to benchmark the reasonableness of a contract against the most recent MPR, the correct MPR to use in the calculation of AMFs remains the MPR from the year of the project bid. This savings against the cost cap damages the RPS process in that it helps to obscure the true cost of renewables and the impact of rising prices for renewable capacity. Dulling of this price signal will lead to false conclusions regarding the cost effectiveness of adding new renewable resources.

- *That has been previously approved, but is requesting a price amendment;*

  Response:

The appropriate MPR to calculate an AMF request for a re-priced contract is the prevailing MPR at the time the project was initially proposed. If a repriced PPA were approved in full and AMFs were calculated based on a more recent MPR, and the contract is above the new MPR, ratepayers would be fully funding the contract at the new price, yet a smaller dent would be made against an IOU's cost cap than if the older MPR were used as a standard for AMFs. This savings against the cost cap damages the RPS process in that it helps to obscure the true cost of renewables and the impact of rising prices for renewable capacity. Dulling of this price signal will lead to false conclusions regarding the cost effectiveness of adding new renewable resources.

It is important to note that if a re-priced contract is not approved and denied AMFs, the impact on ratepayers would be the same. Ratepayers would still pick up the burden because a substitute contract must be found from the current crop of offers, which would undoubtedly have higher bid prices and be benchmarked against a higher MPR.

- *With an expected commercial online date that is unrealistic given expected transmission upgrade needs.*

  Response:

  COD dates are assumed to be reasonable when submitted for the CPUC's consideration since projects have undergone a rigorous screening in offer selection and negotiations. Project delays are almost always due to unexpected delays which are unique to each project. No crystal ball exists to predict project delays.

5. *Discuss whether the following proposed eligibility criteria promote the efficient use of limited AMFs in a manner that maximizes benefits for ratepayers, shareholders, and the RPS Program:*

- *The contract price is an all-in fixed price for a bundled energy product from a RPS-eligible facility;*

  Response:

  The limitation of RPS contracts to fixed price is not useful and may stymie innovation in the development of renewable portfolios. The IOUs have many means of hedging portfolio price risk and should use the most cost effective means at their disposal, rather than having a requirement that RPS contracts also serve the purpose of fixing price.

- *The contract is with an RPS-eligible facility that is physically located in California;*

Response:

This is an unreasonable requirement. This criteria was not in SB1036. In fact, when SEPs were relevant, the CEC did not restrict SEPs to in-state purchases, recognizing out-of-state projects that do "not cause or contribute to any violation of a California environmental quality standard or requirement." It is prudent for California to diversify its RPS portfolio, not only from a technology perspective but also location perspective as well. At times, out-of-state projects could prove to be more cost effective as well. Creating biases against out-of-state renewables will work to the State's – and ratepayers' - detriment as LSEs try to achieve increasingly higher RPS goals and AB32 GHG goals.

- *The project is not otherwise eligible for other Commission-approved funding programs (e.g. Application 07-07-015 pending Commission approval for Emerging Renewable Resource Program (ERRP));*

Response:

A project requiring AMFs should not be restricted to subsidies from one state program, as long as project savings will be passed on to the ratepayers. The same ratepayers who pay for a PPA provide dollars to fund other state programs. Therefore, if a project can obtain one or more subsidies from the ratepayers, the net PPA price will be reduced. The ratepayers pay regardless of which bucket the payment originates. Allowing a project to dip into multiple state funding programs could in fact translate to more renewables being developed because multiple subsidies may reduce a PPA below its MPR and thus not impact the cost cap. (ITC/PTC's are good examples (albeit Federal examples) of double dipping that is common with almost all RPS contracts.) Also, developers and financiers might find multiple subsidies an attractive characteristic of the California RPS.

- *The AMFs request can not include firming and shaping costs.*

Response:

This is an unreasonable requirement, is unduly restrictive and not a part of the Statute. Firming and shaping is a required attribute of some projects with a real cost associated with the service. The cost of firming and shaping has already been scrutinized in LCBF, has proven to be cost competitive as a bundled product with the energy and RECs or else it would not be put forth for CPUC approval. Many renewable technologies are intermittent in nature. Therefore, firming and shaping characteristics make a project attractive to an IOU's portfolio – hence "best fit." This prohibition could be too high of a hurdle for out-of-state resources to overcome. In fact, firming and shaping options provide California with an opportunity to reduce its overall RPS and total portfolio costs by reducing the need for additional transmission to support a project and reducing congestion.

6. *Discuss how a "true-up"[15] of awarded AMFs will or will not affect the financing for a RPS project.*

   Response:

   Once the PUC approves a project's full cost recovery in an IOUs rates, any subsequent true-up must not change that full recovery. To the extent that the PUC does a true-up of associated AMFs, that should have no impact on the project developer who has already received a Commission approved contract, nor should it impact the IOUs future cost recovery.

7. *Identify any material factual disputes that may require an evidentiary hearing.*

   Response:

   SDG&E does not see a need for evidentiary hearings. For SDG&E, we have contracts lined up, which will deplete SDG&E's entire cost cap and estimate the issues teed up in this call for comments will no longer be applicable to SDG&E. The RPS program is better served attending to other program elements that have a greater long term impact rather than getting mired in a protracted proceeding that has a very limited (or no) practical impact.

8. *Draft Resolution E-4160 proposed review standards for contracts with above-MPR costs. In comments, a number of parties questioned whether the Commission review standards should be consistently applied to all contracts. Below is a list of different RPS contract types the Commission reviews. Please comment on whether the Commission should review the following types of renewable contracts using the same or varying review standards. If varying review standards should be used, please provide rationale for using different standards and identify which review standards should apply to which contract types.*

   - *Contracts negotiated as part of a competitive solicitation*
   - *Bilateral contracts*
   - *Short-term contracts*
   - *Long-term contracts*
   - *Contracts with prices greater than the MPR*
   - *Contracts with prices below the MPR*
   - *Projects smaller than ~20 MW*
   - *Utility-scale projects (~ greater than 20 MW)*
   - *New or repowered generation*
   - *Existing generation*
   - *Wholesale distributed generation*
   - *Technologies that have not been commercially demonstrated*

[15] If a project's actual online date differs from the expected online date in the contract, it would likely require a different amount of AMFs.

- *Contracts that are eligible for AMFs*
- *Contracts ineligible for AMFs*
- *AMF need is $1,000,000*
- *AMF need is $70,000,000*

Response:

With regard to review criteria, SB 1036 sets forth only five pre-conditions for counting above-MPR costs of a PPA against the AMF cost limitation:

(A) The contract has been approved by the commission and was selected through a competitive solicitation *pursuant to the requirements of subdivision (d) of Section 399.14*.

(B) The contract covers a duration of no less than 10 years.

(C) The contracted project is a new or repowered facility commencing commercial operations on or after January 1, 2005.

(D) No purchases of renewable energy credits may be eligible for consideration as an above-market cost.

(E) The above-market costs of a contract do not include any indirect expenses including imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades.[16]

As SDG&E noted in its comment on the Draft Resolution, the plain language of SB 1036 makes clear that the review and approval process adopted pursuant to P.U. Code § 399.14 and currently applied to all RPS contracts is sufficient and that no additional review framework is either authorized or required. Indeed, the legislative history of the bill specifically discusses the expectation that "[t]he PUC would use *current practices it has in place* to review renewable contracts for reasonableness, and to make sure the specific contracts are written so they are the least costs and best fit for the IOU's needs."[17] Thus, SB 1036 neither compels nor provides support for adoption of the additional review criteria proposed in the Draft Resolution.[18]

Moreover, imposition of additional layer(s) of review will create unnecessary obstacles to RPS compliance. In an already complicated RPS climate, more rules do not equate to more renewables. Forcing RPS market participants to contend with additional approval processes will, in fact, have the just opposite effect – it

16 SB 1036, Sec. 13, § 399.15(d)(2) (emphasis added).
17 Analysis of SB 1036 by the Assembly Committee on Utilities and Commerce, June 29, 2007, page D (emphasis added). Available at: http://info.sen.ca.gov/pub/07-08/bill/sen/sb_1001-1050/sb_1036_cfa_20070629_131705_asm_comm.html
18 Comments of SDG&E on Draft Resolution E-4160, p. 4.

would divert valuable resources away from contracting for renewable energy and would discourage market participants from developing renewables in California. All of this at a time when the IOUs can ill afford any chilling of the renewables market.

The problem would be compounded if *multiple* review standards are applied to different contract types. This will add significant confusion and create needless work for all parties, including the ED, which would be burdened with establishing subjective ranking criteria if multiple projects spanning multiple contract types seek AMFs.

The arbitrary figure of $1,000,000 ("Tier 1") and $70,000,000 ("Tier 2") in AMFs suggests that the standard of review for Tier 1 is much simpler. The amount of required AMF depends on project size, contract duration, actual year in which the project achieves commercial operation, etc. Tier 1 appears to favor smaller projects over larger project, or 10-year contracts over 20-year contracts, or projects that can come online sooner rather than later. However, depending on an IOU's portfolio need and LCBF results, a larger project might fit better than a smaller, a 20-year PPA might yield a more cost effective unit price – thus better use of AMFs, etc.

Tier 2 suggests ED would place greater scrutiny on a project's viability (i.e. site control, transmission upgrade costs are known). If a project fails and never achieves commercial operation, then the simple fix is to adjust the cost cap by the amount of AMFs the fail project would have accounted for.

To the extent the Commission intends to establish review criteria beyond those set forth in SB 1036, a more practical and reasonable approach is to evaluate AMFs on a project-by-project basis, the merits of which will determine AMF-eligibility. A project's merit should simply be assessed vs. other alternatives an IOU may have. If an IOU presents a case which establishes that the PPA provides the best chance vs. other offers currently available to the IOU and the PPA price is reasonable from an LCBF perspective - that should be sufficient.

The list of contract types above are complicated and suggests unique review standards for each type is necessary. It is impossible to create a rule for every conceivable scenario. SDG&E believes a simpler approach would be to recognize only three types of contracts:

(1) Contracts which are below the MPR. These contracts are per se reasonable.
(2) Contracts which are above the MPR but were competitive versus other offers in a solicitation. These contracts should be deemed reasonable since they passed a competitive market test.
(3) Contracts which are above the MPR but were submitted bilaterally. These contracts need to pass a "strong showing" test.

When procuring certain conventional resources, IOUs are subject to reasonableness reviews which simply require a project pass a "strong showing" test. There is no reason to believe this will not work for RPS procurement. Compelling reasons which could contribute to a project's "strong showing" include:

1. The project fits within an IOU's CPUC-approved LTPP or RPS procurement plan.
2. The project is competitively priced relative to other offers or market benchmark (such as bids into a recent RFO).
3. The project supports the state's RPS or GHG reduction goals.
4. The project supports an IOU's short term, imminent needs.

Simplifying reasonableness review might help California get more renewable projects built by abandoning onerous administrative oversight; thus allowing all interested parties to focus on renewable development.

Original Party Proposals

Please either provide a proposal on how to modify the AMFs proposal in Draft Resolution E-4160 or develop a new methodology for calculating and administering AMFs. Parties are again encouraged to present a proposal that addresses the following five subjects:

1. *Calculation of the cost limitation for above-MPR costs each utility can expend on the procurement of eligible renewable energy resources;*
2. *Methodology for an AMFs Calculator to calculate and track AMFs requests for individual RPS projects;*
3. *Eligibility criteria for power purchase agreements that may be applied to the cost limitation;*
4. *Reasonableness standards for reviewing above-MPR contract costs; and*
5. *(5) Administration rules for the AMFs.*

Also, if working from the attached AMF Calculator, please include a modified spreadsheet that identifies and explains proposed changes.

The line of questioning below suggests that new and complicated reasonableness and accounting rules surrounding AMF-required AND non-AMF required projects need to be established to consider all of the scenarios listed below. More oversight equates to more work for developers, LSEs AND the CPUC without increasing renewables. Lessons need to be learned from the former-SEP program, the demise of which can be attributed, in part, to complicated rules which frustrated renewable development. As more states adopt or increase reliance on an RPS, developers will abandon development in California in favor of more project-friendly states.

The more prudent approach would be to establish simple rules which align State, ESP and developer goals - to cultivate renewable energy.

For original proposals, parties are encouraged to present proposals that address the scenarios outlined below:

a. *A wind contract was negotiated as part of 2006 solicitation, but is not executed and filed with Commission until end of 2008. The project's least-cost best-fit (LCBF) ranking was favorable in comparison to other 2006 bids, but the price has increased from the bid price because wind turbine and other project development costs have increased. What MPR (e.g. 2006 or 2008) should the Commission use in calculating AMFs for the project?*

   The issue of which MPR should be used to measure AMF for a project should be ratepayer sensitive. Regardless of which MPR is used, the full cost of a contract would be borne by the ratepayers anyway. Therefore, using the original MPR relevant to a contract will as least help reduce ratepayer burden via its impact on the cost cap and provide transparency on the true cost of RPS so the correct LCBF portfolio decisions are made.

   Projects which are delayed, if reasonably so, should not be punished (i.e. withdrawing AMFs) but rather supported to achieve commercial operation as soon as possible. Otherwise, a replacement project would likely cost more and would require more AMFs since it would be compared to a higher MPR and would take just as much or more time to come online.

b. *A contract for a project with an above-MPR price was executed in 2008 before any transmission studies were completed. Specifically, the COD in the contract is 12/31/2010, but transmission studies completed after the contract's execution show that major upgrades are needed and it will take an additional 40 months to complete the transmission. The Advice Letter compares the contract to the 2008 MPR with a 2010 online date. What MPR (MPR year and COD) should the Commission use in calculating AMFs for the project?*

   Please see the response to Question a.

c. *A project with a Commission-approved contract has renegotiated its price to reflect higher equipment costs. Should the project be eligible for AMFs? If so, what MPR should the Commission use in calculating AMFs for the project (e.g., original MPR, most recently adopted MPR or does it depend on time lapsed between original and supplemental AL?)?*

   Re-priced contracts, regardless of the reason for re-pricing (increased land, equipment or fuel costs) should still be eligible for AMFs if the proper transparency into the re-pricing is provided by the developer. Re-priced projects are more mature and reflect more realistic costs than those project that have been submitted as proposal to build. Re-priced contracts should be measured relative to the original MPR. At times, higher project costs are outside of a developer control – i.e. they won't buy fuel or equipment until they get a firm contract. Using the original MPR reflects the true cost increase in RPS and should not be obscured by using the latest (higher) MPR.)

d. *A utility requests AMFs for two similar (same technology, capacity, and comparable location) solar photovoltaic projects, and there are not enough AMFs remaining for both projects. One project is slightly above the MPR, while the other one is significantly above the MPR. It may be true that market power is being asserted or that a developer is unrealistically estimating project costs, or that there are project costs that differ between projects. Neither of the first two scenarios is in the ratepayer's best interest: the ratepayer may be overpaying, or a project may not be viable and is tying up AMFs or limited Commission resources may unnecessarily be consumed with processing a price amendment. As a result, how should the Commission determine if one project's costs are more reasonable and realistic than the other? What standards could be applied to determine which contract should be applied toward the utility's cost limitation? Examples of review standards are bid supply curves, cash flow models, and RETI cost curves*[19].

SDG&E believes this is a reasonableness review question, which is outside of the scope of this process, the intent of which is to determine AMF calculation accounting and methodology. However, having said that, SDG&E recommends that reasonableness review should be simpler than the questions posed in this request for comments suggests. By adopting a "strong showing" standard, the CPUC will greatly simplify the process.

An IOU's procurement efforts are overseen by its PRG and IE before being submitted to the CPUC for final oversight and approval. An IOU can only contract with projects that represent the best options available at the time the projects are submitted for the CPUC's consideration. Therefore, as long as an IOU submits projects to the CPUC that represent the best chance to achieve its 20% goals as expeditiously as possible and at prices that reflect current market conditions, that should be a significant factor when considering AMF funding. Otherwise, California will never achieve its RPS goals.

e. *One utility has two projects pending Commission approval that will each require $10 million in AMFs. There is, however, only $10 million in AMFs available. The projects are in various stages of project development with varying capacities and transmission costs. What standards should the Commission use to determine which project should receive AMFs?*

This is a transition issue only, as IOUs approach and exceed their cost cap.

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[19] The RETI cost curve methodology is found in the Phase 1A report and the Phase 1B workplan that is attached to the report as Exhibit A. http://www.energy.ca.gov/2008publications/RETI-1000-2008-002/RETI-1000-2008-002-D.PDF

If both projects pass the “strong showing” test, then both are clearly in the best interest of ratepayers and should therefore both be allowed AMFs.

It is important to note that SDG&E plans to over procure renewables above the 20% mandate and thus would still seek renewables after reaching its cost cap or 20%. The virtues of a project may be so meritorious that the CPUC may approve additional AMFs above the cap, especially if the project passes the “strong showing” test and will take an IOU above the 20% minimum.

f. *A project that received AMFs came online after the online date that was used to calculate the AMFs request. If the AMFs were calculated with the actual online date, additional AMFs would be made available to support another project. How should actual, versus the projected COD, be used to determine the AMFs to be awarded to a project? When should that determination be made?*

Please see the response to Question e.

g. *AMFs are awarded to a project, but the project fails to come online by the contractual online date. At what point should the Commission revoke AMFs and reallocate the funds back to the AMF account or to another project? What standards should be used to make a decision to revoke or reduce AMFs?*

A contract should be considered a failure when the developer or the IOU declares a contract dead.

IV. CONCLUSION

SDG&E supports the development a simple set of guidelines for implementation of SB1036 and appreciates the opportunity to provide comments in advance of the Commission workshop to be held on May 29, 2008. The Commission should ensure that the rules established here accomplish the goals of SB1036 without creating any more procedural “overhead” in an already complex RPS regulatory process than is necessary.

Respectfully submitted this 9th day of May, 2008.

/s/ Kim F. Hassan

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